217/782-2113

CONSTRUCTION PERMIT -- REVISED

PERMITTEE

ExxonMobil Oil Corporation – Joliet Refinery
Attn: Refinery Process Manager
I-55 and Arsenal Road
Joliet, Illinois 60434

Application No.: 01030070 I.D. No.: 197800AAA
Applicant's Designation: Date Received: August 22, 2002
Subject: Low Sulfur Mo-Gas (LSM) Project
Date Issued: September 4, 2002
Location: I-55 & Arsenal Road, Joliet

Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission source(s) and/or air pollution control equipment consisting of the Low Sulfur Mo-Gas (LSM) project as described in the above referenced application. This Permit is subject to standard conditions attached hereto and the following special conditions:

1.0 Unit Specific Conditions

1.1 Unit: LSM Project
Control:

1.1.1 Description

The Low Sulfur Mo-Gas (LSM) project will enable the refinery to produce low sulfur gasoline as required by federal regulation "Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements". Gasoline is made from a number of distinct blend stocks or streams produced at the refinery. This project allows the refinery to remove sulfur from certain streams that currently are not treated at the level required to produce low-sulfur gasoline. This will be done by increasing the capacity of existing desulfurization units (the Pretreater and Hydrofinisher Units) and by installing a new Selective Hydrogenation Unit (SHU) and Naphtha Splitter. As part of this project, improvements will be made to the South Sulfur Recovery Plant, i.e., addition of two additional conversion beds (one per train), to handle the additional sulfur. Low-NO_x burners will be installed in existing heaters and boilers. These improvements are intended to ensure that emissions overall do not increase significantly.

This project also entails increasing the capacity of the Continuous Catalytic Reformer Unit (CCR) to maintain octane and other requirements of the gasoline. These changes to increase sulfur removal and output of high octane material will be accompanied by an increase in emissions from the process heaters and boilers that provide the power for these processes.

This project does not involve modifications to other process units at the refinery, including the Fluidized Catalytic Cracking Unit (FCCU) and Coker Unit.

1.1.2 List of Emission Units and Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
Selective Hydrogenation Unit and Naphtha Splitter	Closed-Vent Systems with Pumps and Compressors	None
Hot Oil Heater (21-B-1)	73 mmBtu/Hr Process Heater with Low-NO_x Burners	None
Pretreater Charge Heater (17-B-1)	112 mmBtu/Hr Process Heater with Low-NO_x Burners	None
Pretreater Debutanizer Reboiler (17-B-2)	164 mmBtu/Hr Process Heater with Low-NO_x Burners	None
CCR Charge Heaters (2-B-3, 4, 5, 6)	Four Process Heaters with Common Breaching (Combined Duty of 680 mmBtu/Hr) with Low-NO_x Burners	None
CCR Reformate Debutanizer Reboiler (2-B-7)	78 mmBtu/Hr Process Heater with Low-NO_x Burners	None
Lean Oil Still Reboiler (8-B-1)	61 mmBtu/Hr Process Heater with Low-NO_x Burners	None
Auxiliary Boiler (55-B-100)	600 mmBtu/Hr Boiler with Low-NO_x Burners	None
South Sulfur Recovery Plant (East and West Train)	Claus Sulfur Recovery Process	Afterburner (11-B-3 and 11-B-23)

1.1.3 Applicability Provisions and Applicable Regulations

a. An “affected process heater” for the purpose of these unit-specific conditions includes the CCR Charge Heaters (2-B-3, 4, 5, 6), PreTreater Charge Heater (17-B-1), the PreTreater Debutanizer Reboiler (17-B-2), the CCR Reformate Debutanizer Reboiler (2-B-7), the Lean Oil Still Reboiler (8-B-1), and the new Hot Oil Heater (21-B-1).

b. i. The affected process heaters are subject to the NSPS for Petroleum Refineries, 40 CFR 60 Subparts A and J. The Illinois EPA administers the NSPS for subject sources in Illinois pursuant to a delegation agreement with the USEPA.

ii. The Permittee shall not burn in the affected process heaters, any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf) [40 CFR 60.104(a)(1)].

c. i. The Permittee shall not cause or allow the emissions of smoke or other particulate matter, with opacity greater than 30 percent, into the atmosphere from an affected process heater [35 IAC 212.123(a)].

ii. The emission of smoke or other particulate matter from the affected process heaters may have an opacity greater than 30 percent but not greater than 60 percent for a period or periods aggregating 8 minutes in any 60 minute period provided that such opaque emissions permitted during any 60 minute period shall occur from only one such emission unit located within a 305 m (1000 ft) radius from the center point of any other such emission unit owned or operated by such person, and provided further that such opaque emissions permitted from each such emission unit shall be limited to 3 times in any 24 hour period [35 IAC 212.123(b)].

iii. Operation of the affected process heaters during startup or malfunction and breakdown may be allowed pursuant to 35 IAC 201, Subpart I, as further provided in operating permit provisions contained in the CAAPP permit.

d. The Permittee shall not cause or allow the emission of carbon monoxide (CO) into the atmosphere from each affected process heater to exceed 200 ppm, corrected to 50 percent excess air [35 IAC 216.121].

1.1.4 Non-Applicability of Regulations of Concern

a. This permit is issued based on the South Sulfur Recovery Plant not being subject to the New Source Performance Standards (NSPS) for Petroleum Refineries, 40 CFR Part 60, Subpart J, because the South Sulfur Recovery Plant has the capacity to handle additional acid gas and the addition of a third reactor bed to each train is not a modification or reconstruction.

b. This permit is issued based on the Auxiliary Boiler not being subject to the New Source Performance Standards (NSPS) for Industrial- Commercial-Institutional Steam Generating Units, 40 CFR Part 60, Subpart Db, because the increased firing of the Auxiliary Boiler is within its capacity and is not a modification or reconstruction.

c. This permit is issued based on the LSM Project not being subject to the New Source Performance Standards (NSPS) for VOC Emissions From Petroleum Refinery Wastewater Systems, 40 CFR Part 60, Subpart QQQ, because it does not include any new individual drain systems or modifications to existing individual drain systems. In the event that a new drain system is required, the Permittee shall apply for an administrative amendment to this permit to address the new system.

d. i. The source has addressed the applicability and compliance of 40 CFR 52.21, Prevention of Significant Deterioration (PSD). The limits in this permit continue to ensure that the action addressed in this construction permit does not constitute a major modification pursuant to these rules, as further explained in Attachments 1 through 5.

ii. For this purpose, this project relies on installation of low-NO_x burner technology in the affected process heaters and the Auxiliary Boiler and installation of a third reactor bed to each train (East and West trains) in the South Sulfur Recovery Plant.

iii. These above requirements and the limitations in Conditions 1.1.5, 1.1.6, 1.1.9, and 1.1.10 become effective when the Permittee begins operation of units in the LSM Project to produce low-sulfur gasoline for commercial sale (i.e., startup of the Selective Hydrogenation Unit, the Naphtha Splitter, and the Hydrofinisher Unit), except that the provisions of Condition 1.1.5(c)(iv) shall become effective upon issuance.

1.1.5 Operational and Production Limits and Work Practices

a. The following emission units shall be equipped, operated, and maintained with low NO_x burners. The burners shall be operated and maintained in conformance with good air pollution control practices.

Lean Oil Still Reboiler (8-B-1)
Hot Oil Heater (21-B-1)
PreTreater Unit Charge Heater (17-B-1)
PreTreater Unit Debutanizer Reboiler (17-B-2)
Reformer Unit Charge Heaters (2-B-3, 4, 5, 6)
Reformer Unit Debutanizer Reboiler (2-B-7)
Auxiliary Boiler

b. Operation of the following emission units shall not exceed the following limits:

Emission Unit	Maximum Firing Rate (mmBtu/Hr)
Lean Oil Still Reboiler (8-B-1)	61
Hot Oil Heater (21-B-1)	73
PreTreater Charge Heater (17-B-1)	112
PreTreater Debutanizer Reboiler (17-B-2)	164
Reformer Unit Charge Heaters (2-B-3,4,5,6)	680
Reformer Unit Debutanizer Reboiler (2-B-7)	78

c. The operation of the Co-Generation Unit (Gas Turbine Generator [20-N-1] and Waste Heat Steam Generator [20-B-1]) shall be coordinated with the operation of the Auxiliary Boiler and the East and West CO Boilers (14-B-3, 14-B-4) as follows:

i. Except as allowed in Condition 1.1.5(c)(iv), when the Co-Generation Unit and East and West CO Boilers are operating, the Auxiliary Boiler shall be operated at a rate not to exceed 295 mmBtu/hr on a daily average basis. This 295 mmBtu/hr daily average limit reflects a 105 mmBtu/hr increase in the annual average firing rate (190 mmBtu/hr) of the Auxiliary Boiler to account for increased steam production associated with this project. This limit may be revised upward in the future as part of the permitting of other projects at the source to account for steam production associated with such other projects.

ii. When the Co-Generation Unit is shutdown or one or both of the East and West CO Boilers is shutdown (including the time period to bring a unit down), the Auxiliary Boiler may be operated at a firing rate above 295 mmBtu/hr (daily average) as needed to make up for reduced operation of the CO boiler(s) or Co-Generation Unit due to equipment failure or unit outage.

iii. For purposes of determining compliance with the emission limits in Condition 1.1.6(a)(i), the Permittee may exclude emissions from the Auxiliary Boiler (55-B-100) associated with the "additional generation" as addressed by Condition 1.1.5(c)(ii).

iv. The Auxiliary Boiler (55-B-100) may be operated in excess of 295 mmBtu/hour for purposes of shakedown/lineout and/or testing. The emissions from such additional firing shall be included when determining compliance with the limits in Condition 1.1.6(a)(i). This permit establishes new requirements for the Auxiliary Boiler as related to the LSM Project that will supersede requirements for the Auxiliary Boiler established by Condition 7.12.5(a) in the CAAPP permit which addresses the prior configuration of the Auxiliary Boiler. This authorization allows for the installation and lineout of low-NO_x burners in the Auxiliary Boiler (55-B-100) during the first phase of the multiphase LSM project construction.

d. i. Each of the trains in the South Sulfur Recovery Plant (East and West) shall be equipped with a third reactor bed.

ii. This permit is issued based on the South Sulfur Recovery Plant treating the additional acid gas generated as a result of this project without any increase in actual SO_2 emissions to the atmosphere. Note: The addition of a third bed to each of the sulfur trains in the South Sulfur Recovery Plant (East and West) will improve the recovery and conversion of sulfur at each train such that, overall, the entire project will result in an actual decrease in SO_2 emissions.

1.1.6 Emission Limitations

a. i. Combined annual emissions from the PreTreater Unit Charge Heater (17-B-1), PreTreater Unit Debutanizer Reboiler (17-B-2), Reformer Unit Charge Heaters (2-B-3, 4, 5, 6), Reformer Unit Debutanizer Reboiler (2-B-7), Lean Oil Still Reboiler (8-B-1), Auxiliary Boiler (55-B-100) and the new Hot Oil Heater (21-B-1) shall not exceed the following limits:

Pollutant	Emissions (Tons/Year)
NO_x	326.2
SO_2	172.1
CO	168.9
VOM	21.4
PM	21.2
PM_{10}	21.2

ii. Combined annual emissions from the Crude Unit Feed Preheater (1-B-3/13-B-4), PreTreater Unit Charge Heater (17-B-1), Reformer Unit Charge Heaters (2-B-3, 4, 5, 6), CHD Unit Charge Heater (3-B-1), and Coker Unit Heaters (16-B-1A, 1B) shall not exceed the following limits. These limitations supersede limitations established in previous permits for these units.

Pollutant	Emissions (Tons/Year)
NO_x	420.7
SO_2	190.6
CO	111.0
VOM	17.6
PM	20.3
PM_{10}	19.7

iii. Emissions of NO_x and CO from the following emission units shall not exceed the following limits:

Emission Unit	NO_x (Lb/mmBtu)	CO (Lb/mmBtu)
Auxiliary Boiler (55-B-100)	0.07	0.0713
CCR Charge Heaters (2-B-3, 4, 5, 6, 7)	0.05	0.015

Emission Unit	NO_x (Lb/mmBtu)	CO (Lb/mmBtu)
CCR Debutanizer Reboiler (2-B-7)	0.04	0.015
Hot Oil Heater (21-B-1)	0.04	0.015
Lean Oil Still Reboiler (8-B-1)	0.045	0.015
PreTreater Unit Charge Heater (17-B-1)	0.04	0.015
PreTreater Unit Debutanizer Reboiler (17-B-2)	0.04	0.015

b. Annual emissions from the FCC Unit, North Sulfur Recovery Plant, and South Sulfur Recovery Plant shall not exceed 2,130.8 tons NO_x, 20,725.8 tons SO_2, 2,816 tons CO, 3.4 tons VOM, and 469.1 tons PM/PM_{10}. Combined emissions from the North Sulfur Recovery Plant and South Recovery Plant of SO_2, when both the North Sulfur Recovery Plant and South Sulfur Recovery Plant are operating, shall not exceed 1,846.8 lb/hr and 8,088.8 tons/year. When the North Sulfur Recovery Plant is out of service, the South Sulfur Recovery Plant emissions shall not exceed 2,482.7 lb/hr of SO_2. These limitations supersede limitations established in previous permits for these units.

c. Emissions of volatile organic material (VOM) from the new* components (i.e., valves, pumps, flanges, etc.) associated with the Low Sulfur Mo-Gas Project including components associated with offsite piping changes related to this project shall not exceed 4.1 tons per year, with emissions calculated using the compliance procedures specified in Condition 1.1.12.

* This limit does not apply to components that are already present at the refinery.

d. Compliance with annual limits shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months (running 12 month total).

1.1.7 Testing Requirements

a. Hydrogen Sulfide Testing for new CEMs.

In accordance with 40 CFR 60.8, within 60 days after achieving the maximum production rate at which the new hot oil heater (21-B-1) will be operated, but not later than 180 days after initial startup of the new hot oil heater (21-B-1) and at such other times as may be required by the Illinois EPA, the Permittee shall conduct performance test(s) in accordance with 40 CFR 60.106(e) and furnish the Illinois EPA a written report of the results of such performance test(s).

Note: The hydrogen sulfide testing requirement is not necessary if existing CEMs are being used.

b. Nitrogen Oxides Testing

i. Within 60 days after achieving the maximum production rate at which the affected process heaters identified below will be operated, but not later than June 30, 2004, the nitrogen oxide (NO_x) emissions of the Reformer Unit Charge Heaters (2-B-3, 4, 5, 6), Pretreater Unit Debutanizer Reboiler (17-B-2) and the Pretreater Unit Charge Heater (17-B-1) shall be measured during conditions which are representative of maximum emissions. (Note: not all affected process heaters are required to be tested.)

ii. The following methods and procedures shall be used for testing of emissions, unless another method is approved by the Illinois EPA: Refer to 40 CFR 60, Appendix A, and 40 CFR 61, Appendix B, for USEPA test methods.

Location of Sample Points	USEPA Method 1
Gas Flow and Velocity	USEPA Method 2
Flue Gas Weight	USEPA Method 3
Moisture	USEPA Method 4
Nitrogen Oxides	USEPA Method 7

1.1.8 Monitoring Requirements

The Permittee shall comply with the Monitoring requirements specified in 40 CFR 60.105 for hydrogen sulfide, as follows:

Pursuant to 40 CFR 60.105(a)(4), the owner or operator shall install, calibrate, maintain, and operate a continuous monitoring system that continuously monitors and records concentrations of hydrogen sulfide in fuel gases burned in any affected process heater, as identified in Condition 1.1.3(a). Fuel gas combustion devices, including any affected process heaters, having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel burned. The span of this continuous monitoring system shall be 300 ppm.

These monitoring system(s) shall be the basis for quarterly reporting of exceedances of the NSPS 40 CFR 60.104(a)(1) (Condition 1.1.3(b)(ii)) in accordance with 40 CFR 60.6(c) and 60.105(e) [See also Condition 1.1.10(a)].

1.1.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items for the affected process heater to demonstrate compliance with Conditions 1.1.3 and 1.1.6:

a. Records for Continuous H_2S Monitoring Systems

The Permittee shall maintain records for each H_2S monitoring system used for affected process heaters as required by Condition 1.1.8 that at a minimum shall include:

i. Operating records for each H_2S monitoring system, including:

A. H_2S measurements;

B. Continuous monitoring system performance testing measurements;

C. Performance evaluations;

D. Calibration checks;

E. Maintenance and adjustment performed;

F. Quarterly reports submitted in accordance with 40 CFR 60.7(c) (Condition 7.7.10(a)); and

G. Data reduction information used pursuant to Condition 7.7.12(c).

ii. Records to verify compliance with the limitations of Condition 1.1.3(b)(ii), including;

A. Hourly H_2S content from each affected process heater as derived from the data obtained by the associated H_2S monitor, gr/dscf;

B. Any three-hour block averaging period when the total H_2S concentration exceeded 230 mg/dscm (0.10 gr/dscf)

b. The Permittee shall maintain records of the following items to demonstrate compliance with Conditions 1.1.5 and 1.1.6:

i. Heat and sulfur content of refinery fuel gas burned in the affected process heaters shall be determined, with supporting documentation, on a representative frequency, i.e., sulfur content shall be determined in accordance with the NSPS 40 CFR 60.105, and heat content shall be determined at least weekly;

ii. Fired fuel duty (gross) from the affected process heaters and Auxiliary Boiler, daily;

iii. Quantity of fuel burned in each affected process heater and the Auxiliary Boiler (mmscf/month and mmscf/yr);

iv. Emissions of SO_2, NO_x, CO, VOM, and PM from the affected process heaters and the Auxiliary Boiler (except as addressed by Condition 1.1.9(b)(vi)) in tons/month, with supporting calculations;

v. Annual emissions of SO_2, NO_x, CO, VOM, and PM from the affected process heaters and Auxiliary Boiler (except as addressed by Condition 1.1.9(b)(vi)) for the current month and the previous 11 months, tons/year; and

vi. For times that the Auxiliary Boiler is fired above 295 mmBtu/hr, the reason why (e.g., the Co-Generation Unit and/or a CO Boiler was shutdown, etc.), and quantification of the emissions resulting from the additional generation allowed by Condition 1.1.5(c)(i) and (ii), that are not included in monthly or annual emission records in (iv) or (v) above.

c. For fugitive emissions from components including components associated with offsite piping changes related to this project:

i. Number of new components by unit or location and type in the Low Sulfur Mo-Gas Project.

ii. Calculated VOM emissions including supporting calculations, attributable to these components determined in accordance with Condition 1.1.12 (tons/year).

1.1.10 Reporting Requirements

a. The Permittee shall notify the Illinois EPA within 30 days of producing low-sulfur gasoline for commercial sale, pursuant to this permit.

b. The Permittee shall promptly (30 days) notify the Illinois EPA, Compliance Section, of deviations of the affected process heaters with the requirements of Conditions 1.1.5 and 1.1.6 (except for deviations addressed by the quarterly reports required in Condition 1.1.10(c) as follows. Reports shall describe the probable cause of such deviations, and any corrective actions or preventive measures taken.

c. Quarterly Report

Pursuant to 40 CFR 60.7(c), the Permittee required to install a continuous monitoring system pursuant to 40 CFR 60 Subpart J (Condition 1.1.8) shall submit a written report of excess emissions (as defined by 40 CFR Subpart J) to the Illinois EPA, Compliance Section for each calendar quarter. This report shall be postmarked by the 30th day following the end of each calendar quarter and shall include the following information:

i. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions;

ii. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of an affected process heater. The nature and cause of any malfunction (if known), the corrective actions taken or preventative measures adopted;

iii. The date and time identifying each period during which the continuous monitoring system was inoperative (except for zero and span checks) and the nature of the system repairs or adjustments; and

iv. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

For the purposes of this report, NSPS 40 CFR 60.105(e)(3) defines an exceedance of sulfur dioxide as "Any three-hour period during which the average concentration of H_2S in any fuel gas combusted in any fuel gas combustion device subject to 40 CFR 60.104(a)(1) exceeds 230 mg/dscm (0.10 gr/dscf), if compliance is achieved by removing H_2S from the fuel gas before it is burned."

d. Two copies of reports and notifications required by this permit concerning equipment operation or repairs, performance testing or a continuous monitoring system shall be sent to:

Illinois Environmental Protection Agency
Division of Air Pollution Control
Compliance Section (#40)
P.O. Box 19276
Springfield, Illinois 62794-9276

and one copy shall be sent to the Illinois EPA's regional office at the following address unless otherwise indicated:

Illinois Environmental Protection Agency
Division of Air Pollution Control
9511 West Harrison
Des Plaines, Illinois 60016

1.1.11 Operational Flexibility/Anticipated Operating Scenarios

N/A

1.1.12 Compliance Procedures

a. Compliance with the firing rate limitations in Condition 1.1.5(b) and (c) shall be demonstrated on a daily average basis by the records required by Condition 1.1.9(b).

b. Compliance with Condition 1.1.6(a)(i) and (ii) shall be demonstrated by the records required by Condition 1.1.9(c) and (d) and appropriate emission factors as identified below, subject to verification by testing in accordance with Condition 1.1.7.

Emissions of VOM, PM and PM_{10} for affected process heaters shall be calculated using standard USEPA emission factors from AIRS as follows:

Process Gas/Natural Gas
VOM 2.8 lb/MM cubic feet burned
PM 3.0 lb/MM cubic feet burned
PM_{10} 3.0 lb/MM cubic feet burned

Emissions of VOM, PM and PM_{10} for the Auxiliary Boiler (55-B-100) shall be calculated using unit specific emission factors based on the manufacturer's guarantee of the following:

VOM 5.5 lb/MM cubic feet burned
PM 4.5 lb/MM cubic feet burned
PM_{10} 4.5 lb/MM cubic feet burned

CO emissions for affected process heaters shall be calculated using the unit specific emission factor listed in Condition 1.1.6(a)(iii).

NO_x emissions for affected process heaters shall be calculated using the unit specific emission factor listed in Condition 1.1.6(a)(iii).

SO_2 emissions for affected process heaters shall be calculated based on the H_2S content of the fuel gas or natural gas.

c. Compliance with Condition 1.1.6(a)(iii) shall be determined from the testing required by Condition 1.1.7(b) for NO_x emissions and by the manufacturer's guarantee for CO emissions.

d. Compliance with the fugitive emission limits in Condition 1.1.6(c) shall be based on the recordkeeping requirements in Condition 1.1.9 and applicable standard emission estimate methodology published by USEPA in "Protocol for Equipment Leak Emission Estimates", EPA-453/R-95-017 (November 1995).

e. i. For purposes of determining compliance with the requirements of Condition 1.1.6(b) and reporting emissions, emissions of SO_2 for the South Sulfur Recovery Plant/Afterburners (11-B-3 & 11-B-23) shall be calculated based on the acid gas flow and H_2S concentration, and the destruction efficiency of the afterburners.

ii. For purposes of determining compliance with the requirements of Condition 1.1.6(b) and reporting emissions, emissions of VOM and PM for the South Sulfur Recovery Plant/Afterburners (11-B-3 and 11-B-23) shall be calculated using AIRS emission factors based on the combustion of refinery fuel gas (supplemental fuel) as follows:

VOM	2.8 lb/MM cubic feet burned
PM	5 lb/MM cubic feet burned

iii. For purposes of determining compliance with the requirements of Condition 1.1.6(b) and reporting emissions, emissions of NO_x for the South Sulfur Recovery Plant/Afterburners (11-B-3 and 11-B-23) shall be calculated using an appropriate emission factor e.g., AIRS emission factors based on the combustion of refinery fuel gas (supplemental fuel) as follows:

NO_x	140 lb/MM cubic feet burned

iv. For purposes of determining compliance with the requirements of Condition 1.1.6(b) and reporting emissions, emissions of CO for the South Sulfur Recovery Plant/Afterburners (11-B-3 and 11-B-23) shall be calculated based on an appropriate unit specific emission factor, e.g. 250 lb/hr/afterburner based on the most recent stack test.

f. Compliance with Condition 1.1.3(d) is considered to be demonstrated by the inherent nature of the operations at this source, as demonstrated by historical operation.

2. The equipment associated with the Low Sulfur Mo-Gas Project may be operated until June 30, 2004 under this construction permit or until a revised Title V permit has been issued incorporating these conditions provided a timely application is submitted to amend the Title V permit to incorporate these conditions.

It should be noted that this permit has been revised to allow additional firing of the Auxiliary Boiler for purposes of shakedown/lineout and/or testing.

Please note that any emission unit included in the Low Sulfur Mo-Gas Project using a control device to achieve compliance with an emission limitation or standard may be subject to CAM (Compliance Assurance Monitoring For Major Stationary Sources).

If you have any questions on this permit, please contact Jason Schnepp at 217/782-2113.

Donald E. Sutton, P.E.
Manager, Permit Section
Division of Air Pollution Control

DES:JMS:jar

cc: Region 1

Attachment 1

PSD Applicability - NO_x Netting Analysis

Contemporaneous Time Period of November 1996 Through November 2001

Table I – Emissions Increases and Decreases Associated With The Proposed Modification

Item of Equipment	Past Actual (Tons/Yr)	Future Potential (Tons/Yr)	Emission Change (Tons/Year)	Permit Number
HDF Charge Heater	0.38	0.00	- 0.38	01030070
Hot Oil Heater	0.00	12.79	12.79	01030070
PreTreater Charge Heater	23.25	19.62	- 3.62	01030070
PreTreater Debut Reboiler	50.63	28.73	- 21.90	01030070
CCR Charge Heaters	118.62	148.92	30.30	01030070
CCR Debut Reboiler	20.49	13.67	- 6.83	01030070
Lean Oil Still Reboiler	28.59	12.02	- 16.56	01030070
Auxiliary Boiler	66.35	90.45	24.10	01030070
SSRP Incinerators	9.30	30.17	20.87	01030070
	Total:		38.77	

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Item of Equipment	Commencement of Operation Date	Emissions Increase (Tons/Year)	Permit Number
None			

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Item of Equipment	Commencement of Operational Change Date	Emissions Decrease (Tons/Year)	Permit Number
None			

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With The Proposed Modification	38.77
Creditable Contemporaneous Emission Increases	0.00
Creditable Contemporaneous Emission Decreases	- 0.00
	38.77

Attachment 2

PSD Applicability - SO_2 Netting Analysis

Contemporaneous Time Period of November 1996 Through November 2001

Table I – Emissions Increases and Decreases Associated With The Proposed Modification

Item of Equipment	Past Actual (Tons/Yr)	Future Potential (Tons/Yr)	Emissions Increase (Tons/Year)	Permit Number
HDF Charge Heater	0.00	0.00	0.00	01030070
Hot Oil Heater	0.00	8.59	8.59	01030070
PreTreater Charge Heater	1.19	13.17	11.98	01030070
PreTreater Debut Reboiler	2.41	19.29	16.88	01030070
CCR Charge Heaters	13.36	79.97	66.61	01030070
CCR Debut Reboiler	1.03	9.17	8.14	01030070
Lean Oil Still Reboiler	0.12	7.17	7.05	01030070
Auxiliary Boiler	0.30	34.69	34.39	01030070
SSRP Incinerators	8542.80	7808.80	- 734.00	01030070
	Total:		- 580.36	

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Item of Equipment	Commencement of Operation Date	Emissions Increase (Tons/Year)	Permit Number
Crude Upgrade Project	1998	584.20	97030078

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Item of Equipment	Commencement of Operational Change Date	Emissions Decrease (Tons/Year)	Permit Number
None			

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With The Proposed Modification	- 580.36
Creditable Contemporaneous Emission Increases	584.20
Creditable Contemporaneous Emission Decreases	0.00
	3.84

Attachment 3

PSD Applicability - CO Netting Analysis

Contemporaneous Time Period of November 1996 Through November 2001

Table I – Emissions Increases and Decreases Associated With The Proposed Modification

Item of Equipment	Past Actual (Tons/Yr)	Future Potential (Tons/Yr)	Emissions Increase (Tons/Year)	Permit Number
HDF Charge Heater	0.10	0.00	- 0.10	01030070
Hot Oil Heater	0.00	4.80	4.80	01030070
PreTreater Charge Heater	5.82	7.36	1.54	01030070
PreTreater Debut Reboiler	12.66	10.77	- 1.89	01030070
CCR Charge Heaters	20.75	44.68	23.93	01030070
CCR Debut Reboiler	5.12	5.12	0.00	01030070
Lean Oil Still Reboiler	7.15	4.01	- 3.14	01030070
Auxiliary Boiler	23.59	92.13	68.54	01030070
SSRP Incinerators	2173.71	2174.30	0.59	01030070
	Total:		94.26	

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Item of Equipment	Commencement of Operation Date	Emissions Increase (Tons/Year)	Permit Number
None			

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Item of Equipment	Commencement of Operational Change Date	Emissions Decrease (Tons/Year)	Permit Number
None			

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With The Proposed Modification	94.26
Creditable Contemporaneous Emission Increases	0.00
Creditable Contemporaneous Emission Decreases	0.00
	94.26

Attachment 4

PSD Applicability - PM/PM_{10} Netting Analysis

Contemporaneous Time Period of November 1996 Through November 2001

Table I – Emissions Increases and Decreases Associated With The Proposed Modification

Item of Equipment	Past Actual (Tons/Yr)	Future Potential (Tons/Yr)	Emissions Increase (Tons/Year)	Permit Number
HDF Charge Heater	0.01	0.00	- 0.01	01030070
Hot Oil Heater	0.00	0.96	0.96	01030070
PreTreater Charge Heater	0.49	1.47	0.98	01030070
PreTreater Debut Reboiler	1.08	2.15	1.07	01030070
CCR Charge Heaters	4.62	8.94	4.32	01030070
CCR Debut Reboiler	0.44	1.02	0.58	01030070
Lean Oil Still Reboiler	0.61	0.80	0.19	01030070
Auxiliary Boiler	2.41	5.81	3.40	01030070
SSRP Incinerators	0.34	0.65	0.31	01030070
	Total:		11.81	

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Item of Equipment	Commencement of Operation Date	Emissions Increase (Tons/Year)	Permit Number
None			

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Item of Equipment	Commencement of Operational Change Date	Emissions Decrease (Tons/Year)	Permit Number
None			

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With The Proposed Modification	11.81
Creditable Contemporaneous Emission Increases	0.00
Creditable Contemporaneous Emission Decreases	0.00
	11.81

Attachment 5

Nonattainment NSR Applicability - VOM Netting Analysis

Contemporaneous Time Period of 1999 Through 2003

Table I – Emissions Increases and Decreases Associated With The Proposed Modification

Item of Equipment	Past Actual (Tons/Yr)	Future Potential (Tons/Yr)	Emissions Increase (Tons/Year)	Permit Number
HDF Charge Heater	0.01	0.00	- 0.01	01030070
Hot Oil Heater	0.00	0.90	0.90	01030070
PreTreater Charge Heater	0.47	1.37	0.90	01030070
PreTreater Debut Reboiler	1.01	2.01	1.00	01030070
CCR Charge Heaters	4.31	8.34	4.03	01030070
CCR Debut Reboiler	0.41	0.96	0.55	01030070
Lean Oil Still Reboiler	0.57	0.75	0.18	01030070
Auxiliary Boiler	2.25	7.11	4.86	01030070
SSRP Incinerators	0.19	0.60	0.41	01030070
Fugitive Emissions	0.00	4.10	4.10	01030070
Cooling Tower Emissions	0.00	0.36	0.36	01030070
	Total:		17.28	

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Item of Equipment	Commencement of Operation Date	Emissions Increase (Tons/Year)	Permit Number
Tanks 587 and 588	2000	5.40	00050087
Benzene Reduction Unit-2	2000	0.00	00060058
	Total:	5.40	

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Item of Equipment	Commencement of Operational Change Date	Emissions Decrease (Tons/Year)	Permit Number
None			

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With The Proposed Modification	17.28
Creditable Contemporaneous Emission Increases	5.40
Creditable Contemporaneous Emission Decreases	0.00
	22.68